ELECTRA
ENERGY CORPORATION

1996 Annual Report

EEN

CORPORATE PROFILE

Electra Energy Corporation is an emerging oil and gas company whose management team is focused on enhancing shareholder value through the prudent use of its capital resources to explore for and develop oil and natural gas reserves in Western Canada.

Electra is a Calgary based, publicly traded Canadian energy corporation trading on the Alberta Stock Exchange under the symbol "EEN".

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held on Tuesday, June 24, 1997, at 11:00 a.m. at the Bow Valley Club, Suite 370, 250 - 6th Avenue S.W., Calgary, Alberta. Shareholders who are unable to attend are asked to complete and return their Form of Proxy to Montreal Trust Company of Canada.

HIGHLIGHTS

	Year Ended December 31, 1996	Year Ended December 31, 1995	% Change
Financial ($000, except per share data)			
Total revenue	**2,196**	2,561	(14%)
Cash flow from operations	**554**	730	(24%)
Per share	**0.04**	0.06	(33%)
Net loss	**(242)**	(100)	142%
Per share	**(0.02)**	(0.01)	100%
Capital expenditures	**1,861**	4,129	(55%)
Total assets	**5,148**	5,133	–
Long-term debt / bank indebtednes	**1,090**	1,305	(16%)
Shareholders' equity	**3,048**	3,074	(1%)
Outstanding common shares (000)	**14,343**	13,067	10%
Weighted average (000)	**13,109**	12,348	6%
Operating			
Daily production			
Oil (bopd)	**275**	325	(15%)
Gas (mcf/d)	**–**	43	(100%)
Total (boepd)	**275**	329	(16%)
Reserves			
Oil (mbbl)	**666**	695	(4%)
Gas (mmcf)	**216**	1,407	(85%)
Total (mboe)	**689**	836	(18%)
Land holdings (net acres)			
Undeveloped	**4,768**	8,200	(42%)
Total	**5,228**	9,259	(44%)
Drilling activity			
Gross wells	**15**	24	(38%)
Net wells	**2.9**	5.1	(43%)
Average prices ($ per boe)	**23.98**	20.79	15%

PRESIDENT'S MESSAGE

The 1996 year was a period of consolidation and restructuring for Electra Energy Corporation. The management of the Corporation spent substantial time reviewing many potential merger and amalgamation candidates. We were not successful in any of our negotiations during the first half of the year and in an attempt to reduce overhead, the Corporation trimmed its staff levels and office space requirements. The beneficial effect of these measures is not fully reflected in the 1996 results, but will be realized in the 1997 year.

In December of 1996, the management team of the Corporation was augmented when Mr. Paul Watson joined Electra as the Vice President of Exploration. Mr. Watson has been involved with several junior to intermediate oil and gas companies in senior management capacities. We welcome his enthusiasm, expertise and experience and it is expected that Mr. Watson will play an integral role with respect to the Corporation's growth.

As at the time of writing the following accomplishments have been achieved:

- a strong management team with proven track records has been assembled
- operational and administrative overhead costs, as they apply to our production base, have been reduced
- two producing property acquisitions for a net 140 boepd to the Corporation have been completed
- two new core areas have been added by drilling and production acquisitions, the first at Ingoldsby Saskatchewan and the second in the West Central area of Alberta
- financings totaling $1,641,000 have been completed
- in excess of 40 drilling locations have been defined

Operations Report

During 1996 the Corporation participated in the drilling of 15 gross wells (2.9 net). Eight wells were cased and completed as oil producers for an overall success rate of 53%. In late 1996 the Corporation participated in its first multi-leg horizontal well in Southeastern Saskatchewan. The result was a high productivity oilwell, which contributed 39 bopd net to the Corporation in December 1996. Currently, stabilized production rates of 25 bopd net to the Corporation have been achieved. Three additional development locations have been defined after a three dimensional seismic program was conducted in early 1997. Drilling operations will commence at these additional development locations during the second and third quarters of 1997.

Subsequent to year-end, the Corporation acquired additional producing properties located in Northwestern Alberta and Southwestern Saskatchewan effective April 1, 1997 and January 1, 1997 respectively. These properties will contribute an additional 60 barrels of light oil and liquids and 800 mcf of gas on a daily basis. With these additions, the Corporation has now achieved a production level of 450 boepd. The combined acquisition price of $3,000,000 represents proven reserve additions of 251,000 barrels of light oil and 3.4 bcf of natural gas for a net price of $5.07 per proven barrel oil equivalent added. Further, a substantial number of development drilling locations on these properties have been identified and are scheduled to commence in mid-1997. Overall, the Corporation anticipates a drilling program of 20 to 25 gross wells in the upcoming year. Included in this program will be the drilling of a deep 15,000 foot Mississippian test in the Paradox Basin in Southwestern Colorado, U.S.A. The Corporation, through its wholly own subsidiary Electra Petroleum (U.S.A.) Inc., has retained a carried working interest position in this 20,000 acre prospect and drilling operations are scheduled to commence in the third quarter of 1997.

In the reporting period, the Corporation continued in its efforts to high-grade its undeveloped land position. The result was the acquisition of 5,600 net acres of exploratory lands during the year and the disposition of interests in several properties in Alberta and Saskatchewan, which no longer met our investment criteria.

Financial Report

The 1996 financial results contained in this report represent management's efforts to maintain a consistent revenue level despite the restructuring and consolidation activities during the year. Gross revenues declined slightly to $2,413,062, a modest 4% decline from 1995.

Cash flow during the year decreased 24% to $553,508 ($0.04 per share) from $729,797 ($0.06 per share) in 1995. With management's efforts to restructure the Corporation, a 9% saving in general and administrative costs from $850,079 to $774,811 was realized. As well, production expenses decreased 11% to $471,636 from $528,348 as a direct result of more effective production operations and lower production rates.

Financially, the Corporation is strong. The credit facility borrowing was reduced at year-end to $1,089,820 from $1,305,203 in 1995. New bank lines have been negotiated to increase the Corporation's available borrowing position to $3,550,000. This financial strength will enable the Corporation to complete its acquisitions, to develop its new core area properties and to avail itself of many new opportunities.

Corporate Strategy

1996 was a year of record activity within the oil and gas industry. This resurgence in activity caused:

- land price escalation
- increased drilling activity and related equipment shortages
- escalating production acquisition prices
- an increased number of mergers and takeovers

To compete in this strong and competitive market environment, the Corporation has focused on the internal generation of drilling projects on which it can drill to earn. Further, the Corporation has aligned itself with partners that have strong technical personnel and sufficient equipment to drill and explore for new reserves. The targeting of production projects with a strong proven undeveloped reserve base will continue in 1997.

On the immediate horizon, we see in excess of $2,000,000 of drilling and development activity which the Corporation will fund with its current cash flow and on-hand cash resources. The Corporation is now set-up to handle hands-on cost and operational control as it applies to our future production base. The Corporation will continue to internally generate its future exploration concepts and seek strategic acquisitions within its current core areas.

Outlook

The current high level of activity within our industry dictates that the Corporation must become a full cycle exploration and production company. Competition for premium return properties is at an all time high. Management of the Corporation believes that the dedication and experience of the technical and business team has positioned the Corporation for significant growth over the next several years.

We have a strong balance sheet, sources of capital for equity financings, and a large drilling program ahead. We look forward to a busy and prosperous 1997.

I would like to thank our shareholders without whose support these accomplishments would not be possible. We at Electra are dedicated to providing you the returns that you deserve.

Thank you for your continued support.

On behalf of the Board of directors,

J. D. Gary Kirkpatrick, President and Chairman of the Board

May 6, 1997

OPERATIONS REVIEW

Land

During 1996, the Corporation continued to add new undeveloped lands in an effort to establish new core areas and to augment existing producing projects. In 1997, this trend will continue as land additions are planned within its new core areas recently established in West Central Alberta and Southeastern Saskatchewan.

Land Holdings (acres)

At December 31, 1996	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	11,103	4,265	2,460	411	13,563	4,676
Saskatchewan	1,344	503	725	49	2,069	552
Total	12,447	4,768	3,185	460	15,632	5,228

Drilling

The drilling rate during 1996 slowed somewhat from that of 1995 as more emphasis was placed upon exploratory work in search of new core areas. Fifteen gross wells (2.9 net) were drilled compared to 24 (5.1 net) in the 1995 reporting period. The drilling program was split almost evenly between exploration (53%) and development (47%), achieving success rates of 25% and 86% respectively. On a combined basis, the overall success rate was 53%. Management has forecast that drilling rates in 1997 will return to 1995 levels with 20 to 25 locations which have been identified for drilling operations. Emphasis will again be placed on developing recent new discoveries and production acquisitions, as well as ongoing exploration programs.

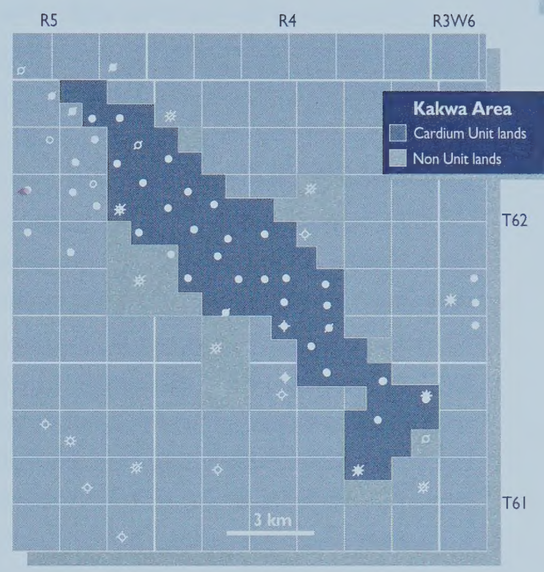
Core Areas

Successful exploration and acquisition programs conducted in late 1996 and early 1997 have resulted in the formation of three main core areas for the Corporation. These areas have been termed West Central Alberta, Southern Alberta and Southeastern Saskatchewan. Each area is anchored by a major production base with proven undeveloped reserves of both oil and natural gas and an abundance of available exploration projects with accessible mineral rights. These core areas are a reflection of management's technical and business expertise and represent a significant opportunity to achieve growth through both the drill bit and an ongoing strategic acquisition program.

Exploration and Development

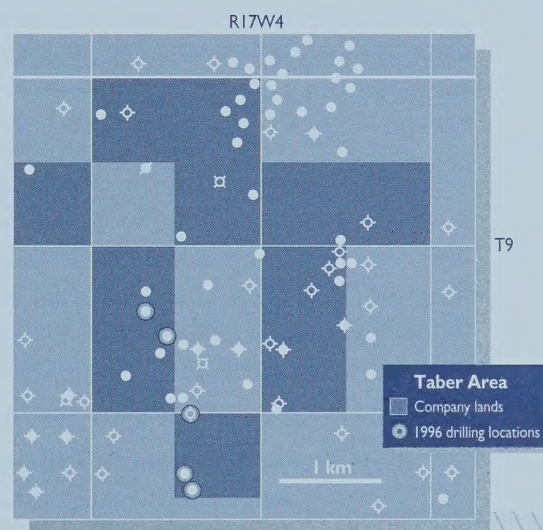
Kakwa, Alberta

During the first quarter of 1997, a 4.55% working interest in the Kakwa South Cardium "A" Pool Unit was acquired. Net daily production to the Corporation is currently 55 barrels of oil and liquids and 150 mcf of gas. The unit operator has identified in excess of twenty development drilling locations and numerous workover operations that should greatly enhance the current level of production. The area is characterized by multiple reservoirs which produce long life reserves, moderate drilling depths whose locations are accessed year round, a complete production infrastructure and a large selection of undeveloped, available crown lands. In conjunction with the unit interest purchase, the Corporation also acquired working interests in non-unitized lands, with interests ranging from 0.5% to 30%. The Corporaton is forecasting that between six and ten wells will be drilled in 1997 commencing in June or July.



Taber, Alberta

Southern Alberta properties remained the mainstay of the Corporation's production base during 1996. The largest producing property is located at Taber, a property that contributed over one half of our average daily oil production (150 bopd net) and 33% of the drilling activity (5 gross wells, .65 net wells) in the reporting period. The ongoing development and expansion of the Taber property will remain a focus for management in 1997. At the present time, three to five drilling locations have been identified for 1997 from our in-house 3-D seismic program.



Grassy, Alberta

As with the Taber property, the Grassy project in Southern Alberta contributed a large portion of our production and drilling base for the year. During 1996, production averaged 65 bopd net to the Corporation and three new gross wells (.46 net) helped to sustain this production level. The producing lower cretaceous Glauconite formation has been delineated with a 3-D seismic survey which indicates that several additional wells could be drilled on the property. The Corporation has budgeted for two additional drilling locations on this project for 1997. Our working interests range from 6.25% to 20%.

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Exploration Areas

Management has turned its exploration focus toward increasing the natural gas production base of the Corporation in order to achieve a better balance of oil versus gas production in our portfolio. Areas rich with natural gas potential from larger, long life reserves have been identified. A variety of exciting drilling projects have been committed to.

West Central Alberta

The most significant area for exploration activity during 1997 and 1998 will be our new core area of West Central Alberta. Anchored by production on both the east and west limits of the area boundary, three exploration projects have now been committed to.

Technical work within a joint venture area to the immediate west of the city of Edmonton (Niton area) has been completed. This area, comprising some 650 square miles, contains multiple gas and oil bearing reservoirs, numerous underutilized gas gathering and processing systems, an abundance of available mineral rights and accessibility at all times of the year. At the time of writing, the first agreement has been reached with a major land owner to drill to earn in the central portion of the block. The Corporation is targeting reservoirs with reserve bases averaging between 5 and 20 BCF per section. Further, lands with existing well bores for re-entry and recompletion work have been identified and are being pursued. We anticipate that this project may be capable of major production additions to the Corporation in late 1997 and early 1998. To meet our internal targets for the year, we have retained a 50% working interest in the joint venture and have budgeted for two wells during 1997.

The Heart River prospect, toward the northern limit of the core area, is characterized by a very large land position which again can be earned by drilling. Typically, the area contains high deliverability sweet gas reserves at shallow depths. Upwards of 30 sections of optioned land can be earned with the "drill bit". The first earning well is scheduled to spud during the second quarter of 1997. As with the Niton project, proximity to gas transmission systems will allow timely tie-ins to market. Further, strategic acquisitions of existing shut in gas reserves are currently being negotiated. The project is controlled by a sizable seismic data base which can be utilized to define additional prospects on offsetting available crown lands. The Corporation has committed to a 10% working interest position in this area and has budgeted for three wells in 1997.

The Corporation is currently finalizing negotiations on a Glauconite sand gas project in the Duhamel area, which is located within the southeastern portion of the core area. Immediately offsetting an older well that drill stem tested natural gas from the Glauconite, a well defined structural prospect is being solidified. The land position comprises a "drilling island" section with an available offset option and crown lands. At this time, the Corporation controls 100% of this project and drilling operations should commence within the third quarter of 1997.

Southern Alberta

Southern Alberta has been the "backbone" exploration and production area for the Corporation since its inception. The area has supplied a major portion of our oil production base and recently a series of natural gas producing properties were acquired. These properties, located immediately to the east of the Alberta/Saskatchewan border, define the eastern boundary of this new core area. The Southern Alberta project area is now supported by production levels of 215 bopd and 350 mcf/d. Previously acquired undeveloped acreage, which offsets our original Taber and Grassy projects, is currently under review. Several areas have been targeted for either drilling operations or farmout potential during 1997. The Corporation will continue with its plans to expand its posi-

tion within this core area.

Southeastern Saskatchewan

In 1996, the Corporation participated in an exploration drilling success at Ingoldsby, in Southeastern Saskatchewan. This success has prompted management to establish a new core area surrounding this discovery, an area well known for its high volume, light oil production. Recent technological advances in horizontal and underbalanced drilling combined with Saskatchewan royalty holidays, have favorably improved the economics of this eastern core area.

Ingoldsby, a project which contributes 25 bopd to our current production base, is the result of the Corporation's first use of this new horizontal drilling technology. As a result of this successful multi-leg horizontal well, a 3-D seismic program was conducted early in the new year. The interpretation of this program indicates the possibility for additional follow up wells to be drilled. The project has been expanded with the addition of both option and crown lands. The Corporation has budgeted for two or three more multi-leg horizontal wells to be drilled during 1997. We have retained an 8.75% working interest in this exploration and development project. An ongoing technical review of this new core area is currently underway with area expansion plans for late 1997 or early 1998.

Corporate Reserves

The volumes and present value of the Corporation's petroleum and natural gas reserves have been evaluated as at December 31, 1996 in two separate independent reserve evaluations. The first is an evaluation of the Corporation's major properties conducted by Sproule Associates Limited. The second is an evaluation of the Corporation's minor property interests conducted by Reliance Engineering Group Ltd. The volumes presented in the following tables represent the Corporation's gross interest in reserves before royalties.

A comparison with December 31, 1995 shows that proven reserve additions based upon drilling results and optimizing operations which enhanced recovery factors for the 1996 period replaced produced oil reserves by 220%. After gas reserve divestitures, probable reserve reductions and the 1996 production, the Corporation's proven reserve base on a mboe comparative basis has essentially remained unchanged.

Reserve Volumes

	Oil & NGLS	Natural Gas
	(mbbl)	(mmcf)
Proven developed producing	451.6	–
Proven developed non-producing	6.1	183.0
Proven undeveloped	130.9	33.0
Total proven	588.6	216.0
Total probable (risked at 50%)	77.3	–
Total proven plus risked probable	665.9	216.0

Present Worth Values (Before Income Taxes and Including ARTC)

($000's)	Undiscounted	10%	15%	20%
Proven developed producing	6,670	4,771	4,203	3,770
Proven developed non-producing	252	167	140	119
Proven undeveloped	1,778	1,193	1,001	850
Total proven	8,700	6,131	5,344	4,739
Total probable (risked at 50%)	1,313	848	709	606
Total proven plus risked probable	10,013	6,979	6,053	5,345

1996 Reserve Reconciliation

	Oil (mbbl)			Gas (mmcf)			Total (mboe)		
		50%			50%			50%	
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total
December 31, 1995	468	227	695	1,407	–	1,407	609	227	836
Additions	54	12	66	–	–	–	54	12	66
Revisions	168	(162)	6	197	151	348	188	(146)	42
Divestitures	–	–	–	(1,388)	(151)	(1,539)	(139)	(15)	(154)
Production	(101)	–	(101)	–	–	–	(101)	–	(101)
December 31, 1996	589	77	666	216	–	216	611	78	689

Pricing Assumptions (January 1, 1997 Evaluation - Sproule Associates Limited)

	Western Canadian Light Crude Oil		Natural Gas
	WTI Cushing, Oklahoma	F.O.B. Edmonton 40° API	Average Price
Year	$US/bbl	$Cdn./bbl	$Cdn./mcf
1997	20.00	26.58	1.65
1998	20.39	26.85	1.80
1999	21.27	27.77	2.08
2000	22.18	29.00	2.19
2001	23.13	30.28	2.32

MANAGEMENT'S DISCUSSION & ANALYSIS

The following discussion and analysis provides an overview of the oil and gas industry in 1996 and a comparative review of the Corporation's operating results and financial position for the years ended December 31, 1996 and 1995. The following should be read in conjunction with the audited consolidated financial statements commencing on page 14 of this report.

In 1996 the oil and gas industry in Canada had significant levels of activity in all areas. Crown land sales were up 17% over those in 1995. Drilling in metres increased 48% from 1995 and well completions grew 36% from the levels in 1995. This activity increase put severe pressure on finding, development and operational costs. Services were harder to contract and more costly, as well; land prices for exploratory rights increased significantly. In particular, drilling rig availability was lower than had been experienced in many years during the 1996 winter season.

In 1996, oil prices displayed strong growth that was not predicted by most analysts. The WTI benchmark price for oil rose 19% to an average U.S. $21.97 per barrel in 1996 from U.S. $18.40 in the prior year. Early in 1996, the consensus of analysts was for moderate backwardation in price, resulting in part from the rumors of Iraqi oil production re-entering the world market. These projections caused many producers to manage price risk through various derivative hedging tools. Natural gas prices also performed well in 1996 with prices in the U.S. growing almost 50% from the prior year. Canadian gas prices rose to a lesser extent during the same period reflecting a 25% increase over 1995.

Treasury financings in the oil and gas industry attained record levels in 1996. A record $9.5 billion from nearly 500 issues was raised, which is a 33% increase in number and 230% increase in dollars over 1995. Of all the financings, 48% were from equity, 30% were from debt and 22% were from other structures, the majority of which were royalty trusts. These higher levels of cash raised in the industry contributed to the high level of activity, the increase in exploration and development, and the increased acquisition costs for oil and gas producing properties.

	1996	1995
Gross oil & gas revenue	**$ 2,413,062**	$ 2,518,254
Hedging gain (loss)	**(217,163)**	42,366
Total revenue (before royalties)	**2,195,899**	2,560,620
Royalties	**(294,405)**	(335,620)
Total revenue (after royalties)	**$ 1,901,494**	$ 2,225,000
Average price received (per boe)	**$ 23.98**	$ 20.79
Oil volume (bbl)	**100,631**	119,566
Gas volume (mcf)	**–**	15,610
Production volume (boe)	**100,631**	121,127
Daily rate (boepd)	**275**	329
Cash flow from operations	**$ 553,508**	$ 729,797
Per share	**0.04**	0.06
Net loss	**242,009**	100,485
Per share	**0.02**	0.01

Gross revenue from oil and gas sales before hedging losses and royalties decreased 4% to $2,413,062 from $2,518,254 in 1995. The decrease was a result of production declines at the Corporation's two major producing properties causing an overall average corporate production decline from 329 boepd in 1995 to 275 bopd in 1996. The majority of the Corporation's drilling success was late in 1996, which had a minor impact on 1996 production rates, but will be reflected in the 1997 period.

The Corporation's production in 1996 was entirely from oil, essentially mirroring 1995. The average price for oil received by the Corporation in 1996 was $23.98/bbl compared to $20.79/boe in 1995. This increase in price was the result of strong market demand for oil in 1996.

In 1996 hedging losses were $217,163 as compared to hedging gains of $42,366 in 1995. The Corporation will continue to closely monitor WTI pricing with a view toward optimizing the use of hedging instruments in the future.

	1996			1995		
	$	**$ Per BOE**	**% of Sales**	$	$ Per BOE	% of Sales
Crown royalties	**115,598**	**1.15**	**5%**	93,983	0.78	4%
Freehold and GORR	**212,723**	**2.11**	**9%**	286,884	2.37	11%
Gross royalties	**328,321**	**3.26**	**14%**	380,867	3.15	15%
ARTC	**(33,916)**	**(0.34)**	**(1%)**	(45,247)	(0.37)	(2%)
Net royalties	**294,405**	**2.92**	**13%**	335,620	2.78	13%

Crown royalties paid in both Alberta and Saskatchewan amounted to $115,598 in 1996, an increase of 23% from $93,983 in 1995. This increase was a direct result of higher commodity prices for oil, increased Saskatchewan production volumes at the Battrum property and the expiration of royalty holidays. As well, production declines were experienced at Taber which is a freehold royalty property. As a result of the production declines, freehold royalties decreased 26% from $286,884 in 1995 to $212,723 in 1996.

In 1996 ARTC decreased 25% to $33,916 from $45,247 in 1995 as a result of lower Alberta crown royalties paid in the period. In 1996 the larger amount of crown royalties was a result of increased oil volumes from the new production facility at Grassy, Alberta, which became operational in October 1995. Increased Alberta royalties for 1996 were more than offset by a crown royalty repayment from the Alberta Crown for production dating back to January 1995.

	1996			1995		
	$	**$ Per BOE**	**% of Sales**	$	$ Per BOE	% of Sales
General and administrative	**774,811**	**7.70**	**32%**	850,079	7.02	34%
Production and operating	**471,636**	**4.69**	**20%**	528,348	4.36	21%
Interest on long-term debt	**101,539**	**1.01**	**4%**	116,776	0.96	5%
Total cash expenses	**1,347,986**	**13.40**	**56%**	1,495,203	12.34	60%
Provision for site restoration	**24,311**	**0.24**	**1%**	34,964	0.29	1%
Depletion and depreciation	**747,806**	**7.43**	**31%**	771,340	6.37	31%
Total non-cash expenses	**772,117**	**7.67**	**32%**	806,304	6.66	32%
Total of all expenses	**2,120,103**	**21.07**	**88%**	2,301,507	19.00	92%

Production Expenses

Operating costs decreased 11% from $528,348 in 1995 to $471,636 in 1996. This decrease resulted partly from lower production levels in 1996 as well as from lower costs associated with the new production facilities at Taber (Spring 1995) and Grassy (Fall 1995) which were realized in 1996.

General and Administrative Expenses

In late 1996 the Corporation restructured its management team to better position itself for growth in 1997 and beyond. The result of this restructuring was a 9% decrease in general and administrative expenses from $850,079 in 1995 to $774,811 in 1996. As a consequence of this restructuring, the Corporation incurred $116,000 of severance costs in the reporting period. Management will closely monitor its G & A expenses in an effort to dedicate as much of its financial resources to exploration and development as possible.

Interest Expense

Interest expense was reduced 13% from $116,776 in 1995 to $101,539 in 1996. This reduction was the result of both lower bank prime interest rates and a reduction in the Corporation's long-term debt position. Management anticipates that interest expense will increase in 1996 as the Corporation returns to a more active acquisition program and the development of its reserves.

Depletion and Depreciation

Total depletion and depreciation decreased to $747,806 in 1996 from $771,340 in 1995. On a per unit of production basis, these charges increased in 1996 to $7.43 per boe from $6.37 per boe in 1995 as a result of the sale of proven non-producing reserves in 1996, and reserve revisions. Management expects that these changes per boe will be reduced in 1997 as a result of recent production acquisitions that provide long life reserves at an optimal price.

As a consequence of property dispositions and 1996 and reserve revisions, the 1996 site restoration provision of $24,311 was 30% lower than the $34,964 booked in 1995. Each year the Corporation, in conjunction with its engineers, reviews its properties to estimate the cost to restore them to their original state. Each year's provision for future site restoration is calculated by multiplying these estimates by the depletion rate.

Ceiling Test

Each year the Corporation performs a ceiling test in accordance with the Canadian Institute of Chartered Accountants' Full Cost Guideline. The ceiling test is a comparison of the net book value of the Corporation's oil and gas properties to the proven potential to be recovered. The 1996 ceiling test was performed based on year-end prices of $26.74/bbl and $1.65/mcf, respectively. Due to the decrease in oil prices in early 1997, management re-performed the ceiling test based on the March oil price of $20.87/bbl received by the Corporation. All calculations resulted in the estimated future net revenues from proved reserves exceeding the net book value of oil and gas properties.

	1996		1995	
	$/BOE	**% of Revenue**	$/BOE	% of Revenue
Oil and gas revenue	**23.98**	**100%**	20.79	100%
Add (deduct):				
Hedging gain (loss)	**(2.16)**	**(9%)**	0.35	2%
Crown royalties	**(1.15)**	**(5%)**	(0.78)	(4%)
Freehold and GORR royalties	**(2.11)**	**(9%)**	(2.37)	(11%)
ARTC	**0.34**	**1%**	0.37	2%
Net after royalties	**18.90**	**78%**	18.36	89%
Operating expense	**(4.69)**	**(20%)**	(4.36)	(21%)
Net cash flows from operations	**14.21**	**58%**	14.00	68%
Add (deduct):				
General and administrative	**(7.70)**	**(32%)**	(7.02)	(34%)
Interest on long-term debt	**(1.01)**	**(4%)**	(0.96)	(5%)
Net cash flow	**5.50**	**22%**	6.02	29%

Lower production and hedging losses were the largest contributing factors to a 24% decrease in cash flow from operations to $553,508 or $0.04 per share in 1996 as compared to $729,797 or $0.06 per share in 1995. The net loss increased to $242,009 or $0.02 per share in 1996 versus $100,485 or $0.01 per share in 1995.

The numbers stated in per share amounts are calculated using the weighted average number of common shares outstanding in 1996 of 13.109 million and in 1995 of 12.348 million.

Tax Pools	Deduction Rate	**1996 $**	1995 $
Canadian exploration expense (CEE)	100%	**563,000**	810,000
Canadian development expense (CDE)	30%	**375,000**	349,000
Canadian oil and gas property expense (COGPE)	10%	**116,000**	128,000
Undepreciated capital cost (UCC)	8% - 30%	**1,629,000**	1,657,000
Cumulative eligible capital (CEC)	7%	**46,000**	50,000
Non capital loss carryforword	100%	**–**	131,000
U.S. tax pools (FEDE)	10%	**359,000**	112,000
Total		**3,088,000**	3,237,000

At the end of the reporting period, the Corporation had $3,088,000 in tax pools compared with $3,237,000 in 1995. There have been no current taxes payable in either the current or prior reporting periods.

Capital Expenditures

	1996		1995	
	$	%	$	%
Land acquisitions	**470,750**	**25%**	618,442	15%
Geological and geophysical	**236,622**	**13%**	324,853	8%
Exploration drilling	**432,460**	**23%**	131,162	3%
Development drilling	**390,067**	**21%**	1,322,912	32%
Facilities and equipment	**274,932**	**15%**	1,656,193	40%
Other	**56,588**	**3%**	75,352	2%
Total	**1,861,419**	**100%**	4,128,914	100%

Capital expenditures were $1,861,419 in 1996, a substantial decrease from the $4,128,914 activity level of 1995. In 1995 significant capital was utilized for both the construction of production facilities and development drilling at the Corporation's major oil producing properties at Taber and Grassy, Alberta. In 1996 only modest capital was required for these properties while more significant amounts were dedicated to exploration activity and crown land acquisitions.

Liquidity and Capital Resources

As at December 31, 1996 the Corporation had a working capital deficit of $457,326 ($128,097 in 1995) and had drawn $1,089,820 ($1,305,203 in 1995) on its bank credit facility. On a year-end 1996 basis, the Corporation's debt to cash flow ratio was slightly less than two times 1996 cash flow. The Corporation secured a $3,550,000 credit line facility subsequent to the year-end that in part accommodated its 1997 production acquisitions.

An equity issue in December 1996 and two separate equity issues in 1997, designed to provide the Corporation with drilling capital in 1997, netted $1,641,000.

Environmental and Safety Issues

Protection of the environment and safety of the public at large are important issues to the Corporation's management and Board of Directors. The Corporation has implemented a corporate Emergency Response Plan and Safety Policy that adhere to government policies and regulations. The Corporation continually monitors government standards to ensure compliance with any changes to these policies and regulations. As well, the Corporation maintains an ongoing program of well site abandonment, clean up and surface restoration to avoid potential environmental problems.

Business Risks

The oil and gas industry is subject to uncertainties and risks including commodity prices, product market demand, exploration success, transportation interruptions, foreign exchange and interest rates, government regulation and taxes and environmental and safety concerns. The Corporation minimizes these risks by diligent management of factors within its control. These factors are managed by the employment of highly qualified professional staff, a strong and flexible financial position, proactive environmental and safety operation procedures, and a focus on low cost reserve additions and cash flow optimization designed to sustain future growth. Geological, geophysical, engineering, environmental and financial analysis are performed extensively on the drilling of new prospects and potential acquisitions. Business risks beyond the control of management include commodity price fluctuations, varying foreign exchange rates, government regulations and various operational interruptions. The Corporation can mitigate certain of these risks by operating in geographical areas characterized by low finding and development costs. Further commodity price fluctuations can be somewhat offset by maintaining a balanced portfolio of oil and gas projects and production.

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CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT TO THE SHAREHOLDERS

All of the information in this annual report is the responsibility of management. The Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles. The financial information elsewhere in the annual report has been reviewed to ensure consistency in all material respects with that in the Consolidated Financial Statements.

The Corporation maintains appropriate systems of internal control to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records provide reliable and accurate information for the preparation of financial statements.

KPMG, an independent firm of Chartered Accountants, has been engaged to examine the Consolidated Financial Statements and provide their Auditors' Report. Their report is presented with the Consolidated Financial Statements.

The Directors are responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Directors exercise this responsibility through the Audit Committee. This committee, which is comprised of Directors of the Corporation, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the Consolidated Financial Statements before they are presented to the Directors for approval. The Consolidated Financial Statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

J.D. Gary Kirkpatrick
President and Chairman of the Board
May 6, 1997

Paul D. Watson
Vice President, Exploration

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Electra Energy Corporation as at December 31, 1996 and 1995 and the consolidated statements of loss and deficit and changes in financial position for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 1996 and 1995 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

KPMG

Chartered Accountants
Calgary, Canada
April 4, 1997

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 1996 AND 1995

	1996	1995
Assets		
Current assets:		
Accounts receivable	$ 434,595	$ 521,632
Prepaid expenses	26,666	26,169
	461,261	547,801
Capital assets (note 3)	4,686,475	4,584,827
	$ 5,147,736	$ 5,132,628
Liabilities and Shareholders' Equity		
Current liabilities:		
Bank indebtedness (note 4)	$ –	$ 1,305,203
Accounts payable	636,587	675,898
Unexpended joint venture commitment	282,000	–
	918,587	1,981,101
Long-term debt (note 4)	1,089,820	–
Future site restoration	22,229	31,601
Deferred income taxes	69,378	45,978
	2,100,014	2,058,680
Shareholders' equity:		
Share capital (note 5)	3,582,076	3,366,293
Deficit	(534,354)	(292,345)
	3,047,722	3,073,948
Commitments (note 8)		
Subsequent events (note 9)		
	$ 5,147,736	$ 5,132,628

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Robert G. Gibson

Director

Director

CONSOLIDATED STATEMENTS OF LOSS AND DEFICIT

YEARS ENDED DECEMBER 31, 1996 AND 1995

	1996	1995
Revenue		
Oil and gas	$ 2,195,899	$ 2,560,620
Royalties net of royalty tax credit	(294,405)	(335,620)
	1,901,494	2,225,000
Expenses		
General and administrative	774,811	850,079
Production and operating	471,636	528,348
Interest on long-term debt	101,539	116,776
Provision for site restoration	24,311	34,964
Depletion and depreciation	747,806	771,340
	2,120,103	2,301,507
Loss before income taxes	(218,609)	(76,507)
Income taxes (note 6)		
Deferred	23,400	23,978
Net loss for the year	(242,009)	(100,485)
Deficit, beginning of year	(292,345)	(126,520)
Cost over assigned value of repurchased shares	–	(65,340)
Deficit, end of year	$ (534,354)	$ (292,345)
Loss per share	$ (0.02)	$ (0.01)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

YEARS ENDED DECEMBER 31, 1996 AND 1995

	1996	1995
Cash provided by (used in)		
Operations		
Net loss for the year	$ (242,009)	$ (100,485)
Items not involving cash:		
Deferred tax provision	23,400	23,978
Depletion and depreciation	747,806	771,340
Provision for site restoration	24,311	34,964
Cash provided by operations	553,508	729,797
Changes in non-cash operating working capital	151,184	326,880
	704,692	1,056,677
Financing		
Issue of share capital:		
For cash	383,033	358,092
On amalgamation	–	214,132
On conversion of debenture	–	141,500
Repurchase of share capital:		
In exchange for cash	–	(25,200)
In exchange for capital assets	–	(180,000)
Long term debt	1,089,820	(141,500)
	1,472,853	367,024
Investments		
Expenditures on capital assets	(1,861,419)	(4,128,914)
Proceeds on sale of capital assets	844,715	864,937
Amalgamation (note 1)	–	(214,132)
Site restoration expenditures	(33,683)	(21,836)
	(1,050,387)	(3,499,945)
Changes in non-cash investing working capital	178,045	294,510
	(872,342)	(3,205,435)
Increase (decrease) in cash position	1,305,203	(1,781,734)
Cash (bank indebtedness), beginning of year	(1,305,203)	476,531
Bank indebtedness, end of year	$ –	$ (1,305,203)
Cash provided by operations per share	$ 0.04	$ 0.06

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 1996 AND 1995

1. Amalgamation

On February 9, 1995 Electra Petroleum Ltd. amalgamated with Lake Placid Resources Ltd. (Lake Placid), a reporting issuer in Alberta, to form Electra Energy Corporation. Each Lake Placid shareholder received one common share of the continuing entity for each ten common shares they previously held. Each Electra Petroleum Ltd. shareholder received one common share of the amalgamated entity for each common share they previously held. The former Electra Petroleum Ltd. shareholders held, immediately following the amalgamation, in excess of 95% of the amalgamated entity's outstanding common shares of which there were a total 12,754,298 issued and outstanding. Electra Petroleum Ltd. was deemed to be the acquirer of Lake Placid.

The business combination was accounted for using the purchase method of accounting and the purchase price was allocated based on fair values as follows:

Current assets	$	29,839
Capital assets		199,166
Current liabilities		(14,873)
Total consideration funded by 520,000 common shares of the continuing entity	$	214,132

2. Significant accounting policies

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Corporation and its subsidiary.

(b) Capital assets:

The Corporation follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs associated with the exploration for and the development of petroleum and natural gas reserves in North America, whether productive or unproductive, are capitalized in cost centres on a country by country basis. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties and drilling and overhead expenses related to exploration and development activities. Proceeds of disposition of petroleum and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized, unless disposition would result in a significant change in the depletion or depreciation rate.

Costs capitalized are depleted and amortized using the unit-of-production method based on gross proved oil and gas reserves as determined by independent engineers. For purposes of the depletion calculation, proved oil and gas reserves are converted to a common unit of measure on the basis of their approximate relative energy content. The carrying value of unproved properties is excluded from the depletion calculation.

The Corporation performs a ceiling test which restricts the capitalized costs less accumulated depletion and amortization, deferred income taxes and the future site restoration from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and gas reserves, based on current prices and costs, and after deducting estimated future site restoration costs, general and administrative expenses, financing costs and income taxes.

Substantially all of the Corporation's petroleum and natural gas exploration and production activities are conducted jointly with others and, accordingly these financial statements reflect only the Corporation's proportionate interest in such activities.

Depreciation of other assets, including leasehold improvements, is based on estimated useful life and is calculated using the declining balance or straight-line basis at rates of 20% to 30%.

(c) Future site restoration:

Future site restoration costs are amortized using the unit-of-production method. These costs are based on year-end estimates of the anticipated costs of site restoration.

(d) Flow-through shares:

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Petroleum and natural gas properties and share capital are reduced by the estimated value of the anticipated tax deductions to be renounced.

(e) Foreign currency translation:

Monetary items denominated in foreign currency are translated into Canadian dollars at exchange rates in effect at the balance sheet date and non-monetary items are translated at rates of exchange in effect when the assets were acquired or obligations incurred. Revenue and expenses are translated at rates in effect at the time of the transactions. Foreign exchange gains and losses are included in income.

(f) Per share amounts:

Per share amounts are calculated using the weighted average number of shares outstanding during the period.

(g) Measurement uncertainty:

The amounts recorded for depletion, depreciation, and amortization of capital assets and the provision for future site restoration are based on estimates. The cost ceiling is based on such factors as estimated proven reserves, production rates, oil and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

(h) Financial instruments:

The Corporation uses derivative financial instruments from time to time to hedge its exposure to fluctuations in oil prices and foreign exchange rates. Gains or losses from these activities are reported as adjustments to the related revenue accounts when the gain or loss is realized.

3. Capital assets

December 31, 1996	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	$ 6,747,891	$ 2,185,824	$ 4,562,067
Other assets	207,392	82,984	124,408
	$ 6,955,283	$ 2,268,808	$ 4,686,475
December 31, 1995			
Petroleum and natural gas properties	$ 5,955,025	$ 1,477,788	$ 4,477,237
Other assets	150,804	43,214	107,590
	$ 6,105,829	$ 1,521,002	$ 4,584,827

During the year, the Corporation capitalized overhead related to exploration and development expenses in the amount of $150,595 (1995 - $148,442). At December 31, 1996, costs of approximately $1,842,000 (1995 - $1,284,000) included in petroleum and natural gas properties had nominal value for income tax purposes. Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 1996 were $410,000 (1995 - $990,000).

A ceiling test calculation was performed at the effective date of December 31, 1996 which resulted in the estimated future net revenues from proved reserves exceeding the net book value of the Corporation's petroleum and natural gas properties. The prices used in the ceiling test calculation at December 31, 1996 were $26.74 per barrel of crude oil and $1.65 per mcf of natural gas. The ceiling test is a cost recovery test and is not intended to result in an estimate of fair market value.

4. Bank indebtedness and long-term debt

The Corporation obtained a $1,500,000 revolving production loan credit facility bearing interest at bank prime rate plus 1% with interest payable monthly. The ceiling amount of this facility reduces by $25,000 per month. The loan is secured by a general assignment of debts, a $5,000,000 fixed and floating charge debenture with a first fixed charge on certain petroleum and natural gas properties and a floating charge on all other assets.

The Corporation has received a waiver from its bank stating that no principal payments are required providing certain conditions continue to be satisfied.

5. Share capital

(a) Authorized:

Unlimited number of common shares without par value.

(b) Issued:

	Number of shares	Amount
Balance, December 31, 1994	11,951,299	$ 2,952,138
Issued on conversion of debenture	283,000	141,500
Issued on amalgamation (note 1)	520,000	214,132
Repurchased and canceled	(540,000)	(139,860)
Issued flow-through shares for cash	852,600	358,092
Effect of tax deductions renounced on flow-through shares issued	–	(159,709)
Balance, December 31, 1995	13,066,899	$ 3,366,293

Issued on the exercise of stock options for cash	26,000		8,033
Issued flow-through shares for cash	1,250,000		375,000
Effect of tax deductions renounced on flow-through shares issued	–		(167,250)
Balance, December 31, 1996	14,342,899	$	3,582,076

(c) As at December 31, 1996, options were outstanding with respect to directors, officers, and certain key employees to purchase up to an aggregate of 1,139,845 common shares at an exercise price of $.30 expiring at various times to December 2001. The Corporation's stock options are granted for a five year period and vest evenly over three years.

(d) Dividends cannot be paid without the bank's prior consent.

6. Income taxes

The provision for income taxes in the statement of loss reflects an effective income tax rate which differs from combined federal and provincial statutory tax rates. The main differences are summarized as follows:

		1996		1995
Loss before income taxes	$	(218,609)	$	(76,507)
Corporate income tax rate		44.6%		44.6%
Computed income tax recovery		(97,500)		(34,122)
Increase (decrease) resulting from:				
Non-deductible crown payments, net		54,616		59,222
Resource allowance		(81,040)		(109,172)
Non-tax base depletion and depreciation		136,154		98,773
Other		11,170		9,277
		120,900		58,100
Actual income tax provision	$	23,400	$	23,978

The Corporation has available tax pools for deduction against future taxable income of approximately $3,088,000 (December 31, 1995 - $3,237,000), some of which may be restricted and be deductible only against revenues from certain properties.

7. Financial instruments

The Corporation uses derivative financial instruments from time to time to hedge its exposure to fluctuations in oil prices and foreign exchange rates. During the year, the Corporation incurred losses of $217,163 under crude oil price and foreign exchange swap contracts which were charged to oil and gas revenue. At the year ended December 31, 1996 the Corporation had one outstanding crude oil fixed price swap contract based on 100 barrels per day at $20.70 U.S. per barrel and the calendar month average West Texas Intermediate price for the six months ended February 28, 1997, settled monthly. The market value of this contract at December 31, 1996 was in a loss position of $37,575 based on a $25.35 U.S. price and a Canadian exchange rate of 1.3696.

8. Commitments

The Corporation is committed to payments under operating leases for office and equipment as follows:

1997	$ 84,891
1998	34,001
	$118,892

9. Subsequent events

(a) Financings:

On January 31, 1997, the Corporation issued 1,000,000 flow-through common shares for a price of $0.35 per share for cash proceeds of $350,000.

On March 27, 1997, the Corporation issued 1,642,244 flow-through common shares and 500,000 common shares for a price of $0.45 per share for net cash proceeds of $916,000.

Effective April 1, 1997, the Corporation increased its bank credit line facility to $3,550,000. This facility reduces by $110,000 per month commencing May 31, 1997.

(b) Acquisitions:

Effective January 1, 1997, the Corporation purchased certain producing oil and gas assets for total consideration of approximately $900,000.

Effective April 1, 1997, the Corporation purchased 100% of the shares of a private corporation which owns an interest in producing oil and gas assets, for cash consideration of approximately $2,100,000.

ELECTRA
ENERGY CORPORATION

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CORPORATE INFORMATION

Management and Directors

J.D. Gary Kirkpatrick
President and Chairman of the Board

Anthony D. Convey
Executive Vice President

Paul D. Watson
Vice President, Exploration

Darin C.M. Roberts
Controller

Robert T. Malcolm, Q.C.
Corporate Secretary, Director

Robert G. Gibson
Director

Thomas F. Goodenough
Director

John A. Kaye
Director

Head Office

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Calgary, AB T2P 1E5

Auditors

KPMG
1200, 205 - 5 Avenue S.W.
Calgary, AB T2P 4B9

Legal Counsel

MacKimmie Matthews
700, 401 - 9 Avenue S.W.
Calgary, AB T2P 2M2

Evaluation Engineers

Sproule Associates Limited
900, 140 - 4 Avenue S.W.
Calgary, AB T2P 3N3

Reliance Engineering Group Ltd.
1304, 505 - 3 Street S.W.
Calgary, AB T2P 3E6

Registrar and Transfer Agent

Montreal Trust Company of Canada
Stock Transfer Services
600, 530 - 8 Avenue S.W.
Calgary, AB T2P 3S8

Stock Listing

Alberta Stock Exchange "EEN"

Abbreviations

bbl	barrel
bopd	barrels of oil per day
mbbl	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
boe	barrel oil equivalent (1 barrel of oil = 10 mcf of gas)
boepd	barrels oil equivalent per day
mboe	thousand barrels oil equivalent
W.I.	working interest
WTI	West Texas Intermediate benchmark oil price

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